CHAPTER V

ECONOMIC ANALYSIS

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A. INTRODUCTION

The purpose of this chapter is to present an economic evaluation of electric power production from geopressured geothermal resources in Texas. An effort has been made to obtain the most realistic data concerning the investment and production costs of a geothermal power generation system, sited on a model geopressured geothermal resource.

Resource assessment studies indicate that commercially attractive geopressured geothermal resources exist in several "fairways" in Texas and Louisiana at depths of 12,000 to 20,000 feet. Typically, the temperature of the high-pressure brines (9,000 to 15,000 psia) ranges from 275°F to 375°F, with a realistic temperature being about 325°F. Well logs give reasonable information concerning temperature and pressure, but data concerning total dissolved gases and solids content are not available. As considerable quantities of methane are currently being produced out of the top of geopressured zones in Texas and Louisiana, it is expected that methane will be present in these waters. However, specific data are not available; a reasonable guess would be that the waters are near saturation content of methane at the given reservoir pressure and temperature. This guess appears reasonable in light of various models for the formation and deposition of petroleum. Models for dissolved solids content are in disagreement; any model resource, therefore, can only include a crude guess of the dissolved solids content and profile. Producibility of the resource also is an open question requiring actual reservoir testing to establish the facts.

The system considered in this chapter consists of a 25 MW(e) power plant and a methane production fuel plant, which also includes the well field. The total investment cost of the entire system (power plant, fuel processing plant, and well field) is estimated to be 101 million dollars. It has also been estimated that gas and electricity production could begin within five

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years of field discovery. Expected annual production is assumed to be approximately 200 million kW(e)hr and 5,000 million standard cubic feet of gas. The system has an estimated economic life of 30 years and is shown to have an internal rate of return of almost 12 percent. This illustrates that, for Texas, geopressured geothermal energy utilization, for resources of quality equivalent to or superior to the assumed resource model, is economically feasible.

Two specific economic analysis tasks are considered:

(1) Investigation of economic feasibility of overall project, of fuel plant, and of generation plant.

(2) Investigation of methodology for equitable pricing of geothermal fluids.

Overall feasibility of the project can be established by splitting the project into a fuel plant (including well field) and a power plant and applying appropriate accounting to each portion. Because overall economic feasibility is being determined, the cash flow represented by hot water fuel payments is an internal cash flow which, except for royalty payments, does not effect the final result.

Economic feasibility of the two components - fuel plant and power plant - must obtain individually if separate ownership is to be considered. This scenario requires that internal rates of return of the two components of the project be comensurate with investment practice in the resource recovery and electric utility industries, respectively. All investment, sales, and operations and maintenance costs can be specified by economic models. The economic value of the hot, pressurized geothermal fluid ("fuel") is the only variable in the analysis which is not directly effected by current cost factors and practice. This value can be adjusted in order to adjust the profitability of each venture. It is clear, however, that external market prices for methane and for electricity will have very direct bearing upon the geothermal fluids "fuel" price to the power plant.

Several variations of fuel plant analysis have merit:

(1) Fuel plant without consideration of intangibles and depletion allowance; 100% debt financing.

(2) Fuel plant with inclusion of intangibles but without consideration of depletion allowance; 100% debt financing.

(3) Fuel plant with inclusion of intangibles and depletion allowance; 100% debt financing.

(4) Fuel plant with consideration of intangibles and depletion allowance plus part equity financing with remainder being debt financing.

Full debt financing of the fuel plant is assumed in all analyses discussed here as the trends of equity financing which developed after World War II have altered during the last two years and definitive new patterns have not emerged. Further, full debt financing is also assumed for the power plant as a new pattern for utility equity financing has not yet stabilized. In each case, the full debt financing assumption should be conservative, indicating a somewhat less profitable investment analysis.

SPECIFIC MODELS ANALYZED:

(1) Fuel plant and power plant in single project with 100% debt financing and 100% tangibles in the well field.

(2) Fuel plant and power plant in separate projects with hot water payment from latter to former:

(a) 100% debt financing; 100% tangibles.

(b) 100% debt financing; estimated tangibles and intangibles.

(c) 100% debt financing; estimated tangibles and intangibles; 15% water depletion credit to fuel plant.

Variation of the hot water payment (made by the power plant to the fuel plant) allows study of the sensitivity of the two plants to the hot water price and provides a methodology for setting the hot water price for the model resource project.

RESOURCE MODEL:

Table V-1 shows the characteristics of the geopressured geothermal source which may be expected in Texas. These data were developed from a detailed fairway study which utilized well logs and seismic survey data.

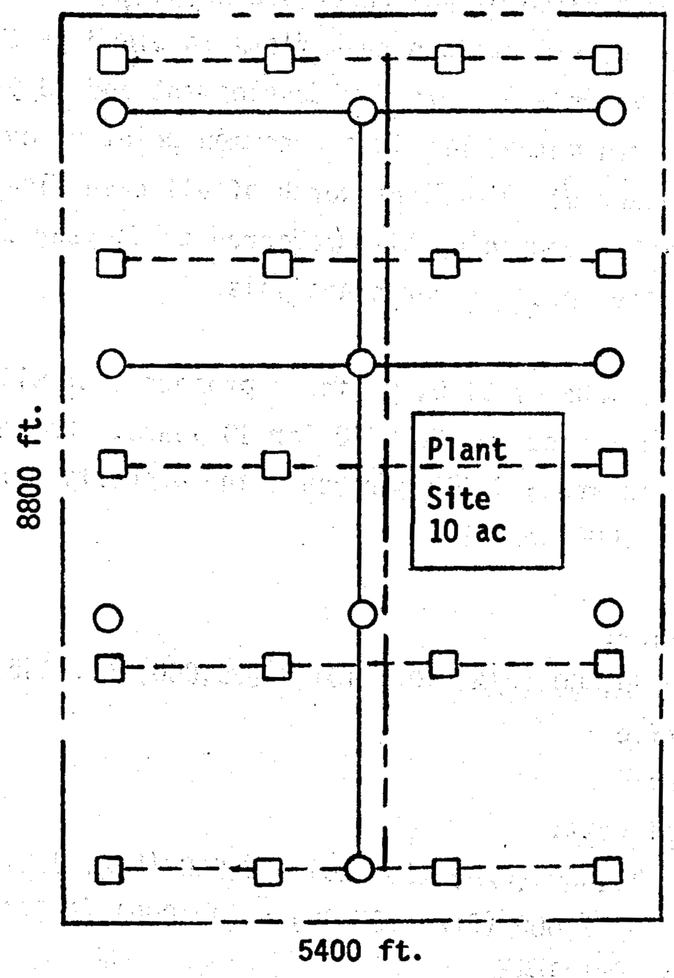
TABLE V-1

GEOTHERMAL SOURCE CHARACTERISTICS MODEL

Source Well Depth	14,000 Feet
Single Well Flow	[1]40,000 BBL/Day of geothermal brine
Total Dissolved Solids	[3]10,000 PPM
Temperature	325°F
Methane Content	[2]40 SCF/BBL
Useable Well Head Pressure	[1]2000 PSIA
Silica Content	Not to be considered
Source Wells Spacing	[1]Half Mile
Maximum No. of Wells per Aquifer	[1]Twelve

1. Estimated using simple oil and gas reservoir theory
2. Estimated using methane saturation data for fresh water
3. Estimated using very limited data; new data indicates salinities of 20,000 - 30,000. Characteristic awaits drilling verification.

Figure V-1 shows a plot plan of the geopressured geothermal electricity generation system. Note that there are two reinjection wells per production well. The reinjection wells will be 6,000 feet deep and the cost of each well will be about half of the cost of each production well. The economic life of the well field has been estimated to be 20 years, but it could be extended up to 30 years by development of new production and reinjection wells. This redevelopment has an estimated cost of about half of the initial investment of the field. Economic life for the fuel processing plant and power plant are taken as 30 years.



□ Production Wells ½ Mile Spacing

○ Reinjection Well

Figure V-1: Geopressured geothermal project plot plan.

B. METHOD OF ANALYSIS - PRESENT WORTH

The following section provides documentation of the method used to evaluate the actual economic value of the geopressured geothermal project under consideration. The investments and cash flows involved in this project occur over a period of 35 years - 5 years for development and 30 years for operation. The present worth method provides a common point of evaluation which is based on the concept of equivalent worth of all cash flow and investment as of some base or beginning time (referred to as year zero). The following example illustrates present worth analysis.

Example:

An investment is made of $100,000 for a project that will produce a uniform annual revenue of $30,000 for 10 years. Operations and maintenance costs are $10,000 per year, and property taxes and insurance are $2,000 annually.

Solution:

i. PW of inflow:

Revenue: 30,000 (P/A, 10%, 10) = (39,000) (6.1446) = 184,338

ii. PW of outflow:

Investment: = 100,000

Total Cost:

10,000 (P/A, 10%, 10) + 2,000 (P/A, 10%,10)

= 12,000 (P/A, 10%,10) = (12,000) (6.1446)= 73,735

Total Outflow:

100,000 + 73,735 = 173,935

Since 184,338 > 173,735, a profit obtains and the project is worthy of further consideration. The following graphs illustrate cash outflows and inflows for the project. Figure V-2 shows all the cash flows as they occur annually and Figure V-3 shows the present worth of the net cash flows (cash inflow - cash outflow) for the 10 year period with time zero as the base year.

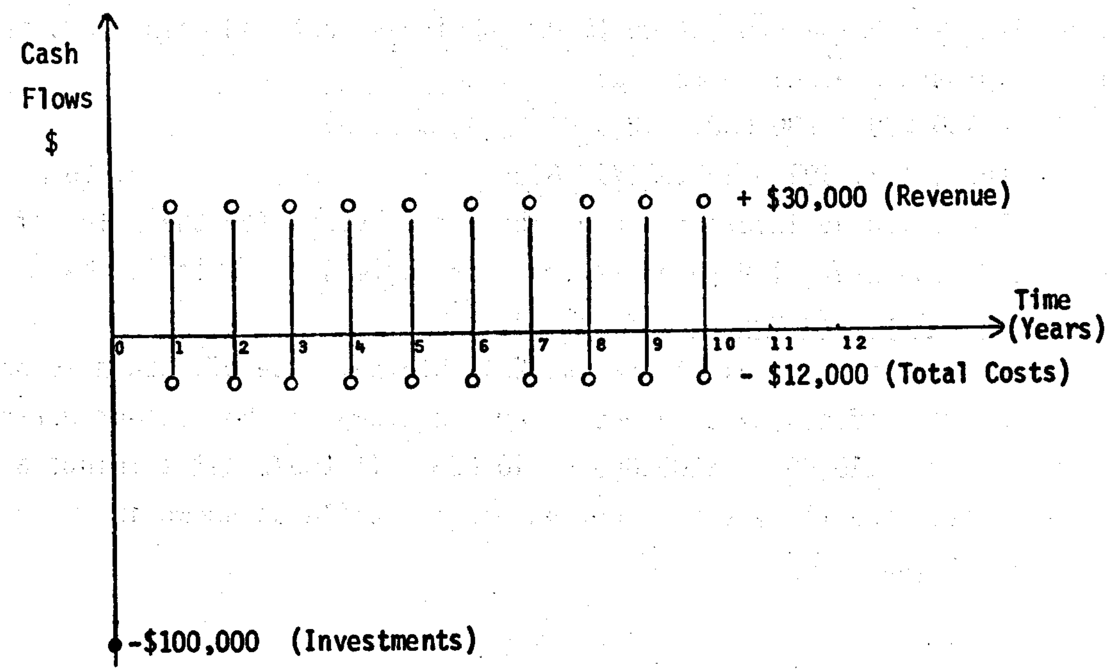


Figure V-2: Cash flow profiles.

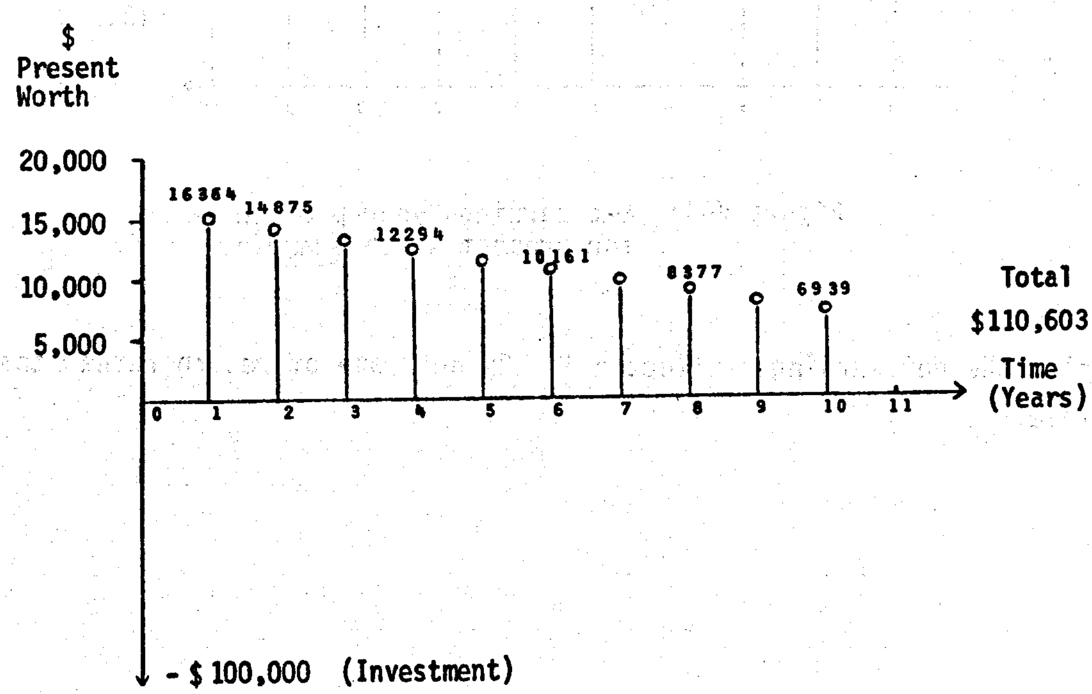


Figure V-3: Present worth of cash flows using interest rate i=10%.

The internal rate of return for the project is the discount rate (interest) at which the present worth of the investment and cash flows sum to zero. For the preceding example:

$$- 100{,}000 + (30{,}000 - 12{,}000)\ (P/A,\ i'\%, 10) \qquad = 0$$

$$(P/A,\ i'\%,\ 10) = 100{,}000/18{,}000 \qquad = 5.556$$

The compound interest tables for n = 10 years for the value of 5.556, yields an internal rate of return just above 12%. This is the <u>internal rate of return for the project</u> - 12^{+}%.

It is important to realize that a 12^{+}% internal rate of return is not the same as a 12% after tax earnings. For the example: the present worth net earnings are \$110,603 - \$100,000 = \$10,603. If these net earnings are distributed over the ten years, a net earnings profile as shown in Figure V-4 obtains:

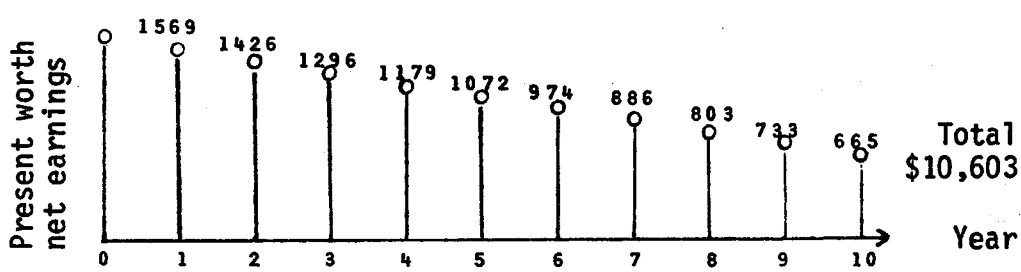


Figure V-4: Net earnings year profile for present worth example.

Clearly, the net earnings reflect a 1 - 2% net rate of return rather than a 12% rate.

TREATMENT OF SOME SPECIFIC FACTORS:

It is appropriate at this point to provide some details concerning how certain factors - intangibles in drilling, depletion allowance, geothermal fuel payments - are included in the present worth analysis. Intangible costs in drilling - equipment rental, drilling mud, professional services, drill rig charges - are treated as current year operating costs and are present-worthed back to year zero of the project. Depletion allowance is a before tax allowance* which is calculated either as:

(1) 15% of revenues (water depletion), or

(2) 50% of after tax earnings.

For all calculations, depletion allowance is determined using the minimum allowance which is calculated from the two above options. Further, the 15% water depletion allowance is used instead of the 22.5% oil and gas depletion allowance as the latter will need to be litigated to establish its applicability. The depletion allowance, of course, decreases annual tax burdens and increases the net worth of annual cash flows.

The hot brine fuel payment from the power plant to the fuel plant is accounted as a fuel cost to the power plant and a revenue to the fuel plant. The hot brine fuel payment is calculated in terms of dollars per million Btu; the available Btu content is taken as plant fence enthalpy ($320^\circ F$, 300 psia, 291 Btu/lb_m) minus condenser saturated liquid enthalpy ($110^\circ F$, 2 psia, 78 Btu/lb_m).

C. SYSTEM DESCRIPTION AND COST

The geopressured geothermal power generation system costs were estimated for a fuel plant and a power plant, with allocation of costs as shown in Tables V-2, V-3, V-4 and V-5. Tables V-2 and V-3 show the preliminary system development costs; Tables V-4 and V-5 show the fuel and power plant costs, respectively; Table V-6 gives an overall summary of investment. Figures 8 and 12 in Appendix B show the plans of the fuel and power plants, respectively, for the two-stage flash-steam generation plant analyzed.

*Only percentage depletion is considered in this report; cost depletion is assumed to be less than percentage depletion.

TABLE V-2

PRELIMINARY DEVELOPMENT COST FOR FUEL PLANT

Fairway Review and Selection of Target	$ 275,000
Obtain Option for Land Exploration	$ 20,000
Environmental Baseline Fuel Plant	$ 110,000
Seismic, Geology, Site Specification	$ 250,000
Obtain Lease and Rights of Land Use	Not Available
Drill Test Well	$2,350,000
Drill Reinjection Well	$1,000,000
Test Facility Design and Heat Exchanger	$ 120,000
Installation of Test Facility	$ 200,000
Test Facility Fuel Plant	$ 550,000
Production and Reinjection Wells Test	$ 240,000
Conceptual Design Fuel Plant	$ 315,000
Well Field Design	$ 100,000
Fuel Plant Detailed Design	$1,000,000
Buy Land for Fuel Plant	$ 20,000
TOTAL	$6,550,000

TABLE V-3

PRELIMINARY DEVELOPMENT COST FOR POWER PLANT

Environmental Baseline Power Plant	$ 110,000
Conceptual Design Power Plant	$ 635,000
Power Plant Detailed Design	$2,000,000
Buy Land for Fuel Plant	$ 20,000
Test Key Module Prototype Power	$ 295,000
TOTAL	$3,060,000

TABLE V-4

FUEL PLANT COST

Fuel Plant Site Development	$ 430,000
Step-Out Drilling of Field	$38,640,000
Methane Separators	$ 1,177,000
Well Field Redevelopment	$24,000,000
Miscellaneous Equipment as Follows:	
Pipes	$ 1,909,000
Pumps	$ 113,000
Coolers	$ 17,000
Compressors	$ 324,000
Water Separators	$ 15,000
Filters	$ 4,000
Glycol Separator	$ 109,000
Fuel Plant Structures	$ 2,340,000
Installation of Major Equipment	$ 2,340,000
TOTAL COST OF FUEL PLANT	$71,418,000

1. Add new production wells and plug back old production wells for use as injection wells.

TABLE V-5

POWER PLANT COST

Site Development	$ 425,000
Foundation and Structure	$ 1,820,000
Cooling Tower	$ 1,210,000
Chilled Water System	$ 27,000
Dryer	$ 7,000
Vacuum Pump	$ 138,000
Condensate Recirculation Pump	$ 11,000
Cooling Tower Recirculation Pump	$ 213,000
Surface Condenser	$ 450,000
Steam Separator S-2	$ 68,000
Steam Separator S-3	$ 47,000
Flash Chamber 1	$ 55,000
Flash Chamber 2	$ 100,000
Hydraulic Turbine	$ 275,000
Generator for Hydraulic Turbine	$ 112,000
Steam Turbine-Generator Set	$ 3,645,000
Step Up Transformer Station	$ 200,000
Control System	$ 380,000
Fire Protection System	$ 220,000
Installation Cost	$10,250,000
Contingency on Cooling System	$ 74,000
TOTAL COST	$19,727,000

TABLE V-6

SUMMARY OF INVESTMENT

Preliminary Development Cost Fuel Plant	$ 6,550,000
Preliminary Development Cost Power Plant	$ 3,060,000
Power Plant	$ 19,727,000
Fuel Plant (Includes Well Field)	$ 71,418,000
TOTAL	$100,755,000

D. CASH FLOW

1. OUTLINE OF CASH FLOW

a. The geothermal geopressured fuel/power system revenue will come from two major sources:

(1) Revenue from electricity sales.

(2) Revenue from gas sales.

b. The fixed charges of the system can be classified as:

(1) Insurance.

(2) Taxes.

(a) Property tax.

(b) Production taxes:

i. Gas well head severance tax.

ii. Electricity generation regulation tax.

(c) Federal income tax.

(3) Depreciation.

(4) Amortization (investment).

c. Operating and maintenance charges include:

(1) Royalty payments.

(2) Operations and maintenance costs.

(a) Salaries and wages.

(b) Maintenance repair.

(c) Supervision and engineering.

(d) General administration & overhead.

d. The cash flow will be divided into six different periods as shown on Table V-7.

TABLE V-7

CASH FLOW COMPUTATION PERIODS

PERIOD	FROM	TO
I	1980	1985
II	1985	1990
III	1990	1995
IV	1995	2000
V	2000	2005
VI	2005	2010

2. REVENUE CASH FLOW

2.1 Revenue from Electricity Sales

The annual revenue from electricity sales is equal to the total electric power sold times the price of electricity during that particular year.

$$R = P_s \times K_e \tag{1}$$

The power plant is designed to produce 25 MW(e) of continuous power. The actual electric power that is available for sales can be calculated considering the following factors:

a. Electric power used in power plant

$$P_p = 4.8\%$$

b. Power transmission and distribution losses

$$P_{td} = 3\%$$

c. Production availability (time of operation)

$$T_p = 90\%$$

d. The net electric power produced

$$P_{net} = P_{gross} - P_p \tag{2}$$

$$P_{net} = 25 \text{ MW(e)} - 25 \text{ MW(e)} \times 0.048$$

$$P_{net} = 23.8 \text{ MW(e)}$$

e. The total continuous power available to customers

$$P_{total} = P_{net} - P_{td} \tag{3}$$

$$P_{total} = 23.8 \text{ MW(e)} - 0.03 \times 23.8 \text{ MW(e)}$$

$$P_{total} \cong 23.1 \text{ MW(e)}$$

The total power available for sales per year is equal to

$$P_s = T_p \times P_{total} \times \frac{\text{\# hours}}{\text{day}} \times \frac{\text{\# days}}{\text{year}} \tag{4}$$

$$P_s = 0.90 \times 23.1 \text{ MW} \times \frac{10^3 \text{kW}}{\text{MW}} \times \frac{24 \text{ hr}}{\text{day}} \times \frac{365 \text{ days}}{\text{year}}$$

$$\boxed{P_s = 1.82 \times 10^8 \ \frac{\text{kW-hr}}{\text{year}}}$$

Presently, the average busbar price of electricity in Austin, Texas is 42 mills per kW-hr. This price obtains because Austin generates with natural gas recently spot-purchased on the Texas intrastate market or with longer-term contract gas, the contract price of which was abrogated (altered) by ruling of the Texas Railroad Commission. Most gas generation will approach these high busbar rates as old gas contracts run out and new prices begin to predominate. An anticipated conversion to oil firing (from gas firing) offers short-term relief, but should all gas generation in the gas-producing states switch, pressure on oil supply and foreign exchange may result in oil firing costing much more than contemporary gas firing.

The price of electricity is increasing continuously. Table V-8 shows the expected electricity sales price in Texas for the next 36 years, assuming a 2.5 percent per year annual busbar price escalation. Table V-9 shows the present worth of electricity sales revenue for the different periods assuming various discount rates.

TABLE V-8

ELECTRICITY SALES PRICE IN TEXAS (K_e)

YEAR	PRICE (MILLS/ kW-hr)	PRICE INCREMENT (MILLS/kW-hr)
1975	42	-
1980	48	6
1985	54	6
1990	60	6
1995	69	9
2000	78	9
2005	88	10
2010	100	12

TABLE V-9

REVENUE FROM ELECTRICITY SALES

PERIOD	AVERAGE ANNUAL RATE (MILLION $)	PRESENT WORTH (MILLION $) at indicated discount rates		
		8%	10%	12%
I	9.28	25.77	22.27	19.25
II	10.37	19.33	15.11	11.82
III	11.83	14.73	10.42	7.37
IV	13.49	11.22	7.18	4.60
V	15.11	8.46	4.90	2.84
VI	17.11	6.57	3.44	1.80
TOTAL	12.87*	86.08	63.32	47.68

*Six period average

2.2 Revenue from Gas Sales

The annual revenue from gas sales is equal to the total gas sold times the Btu content of the gas times the price of the energy (per Btu).

$$R_G = G_{total} \times E \times K_G \tag{5}$$

The daily production of methane is estimated to be

$$G_D = 13.65\ \bar{\mathrm{M}}\mathrm{SCFD}$$

Gas is continuously available during well field operation; the well field is assumed available for production 100% of the time even though the power plant is not. Therefore, the total annual production of gas is expected to be

$$G_{total} = 13.65\ \bar{\mathrm{M}}\mathrm{SCFD} \times 365\ \frac{\mathrm{day}}{\mathrm{year}}$$

$$G_{total} = 4{,}982.25\ \frac{\bar{\mathrm{M}}\mathrm{SCF}}{\mathrm{year}}$$

The energy content of gas is estimated to be

$$E = 1 \times 10^3 \frac{\text{Btu}}{\text{SCF}}$$

The present price of natural gas is assumed as

$$P_G = 2.00 \frac{\text{dollars}}{10^6 \text{ Btu}}$$

Table V-10 shows the expected sales price of natural gas for the next 35 years, assuming a 2.5 percent per year escalation factor.

TABLE V-10

GAS SALES PRICE IN TEXAS (K_G)

YEAR	PRICE* $/10^6 Btu	PRICE INCREMENT $/10^6 Btu
1975	2.17	-
1980	2.45	0.28
1985	2.78	0.33
1990	3.14	0.36
1995	3.56	0.42
2000	4.02	0.46
2005	4.55	0.53
2010	5.15	0.60

* A baseline price of $2.00 excluding severance tax is assumed. The $2.17 is perhaps 5-10¢ higher than some spot-purchase prices on Texas intrastate market.

Table V-11 shows the expected revenue from methane sales. The figures on the table have been calculated according to equation (5) and the price of gas as indicated on Table V-10.

TABLE V-11

REVENUE FROM GAS SALES

PERIOD	AVERAGE ANNUAL RATE (MILLION $)	PRESENT WORTH (MILLION $) AT INDICATED DISCOUNT RATES		
		8%	10%	12%
I	12.46	34.67	29.95	25.90
II	14.94	27.38	21.40	16.74
III	16.49	20.62	14.59	10.33
IV	18.78	15.62	10.00	6.40
V	21.03	11.81	6.84	3.96
VI	24.16	9.03	4.73	2.48
TOTAL	17.98*	119.13	87.51	65.81

*Six period average.

3. DISBURSEMENTS

a. Fixed Charges

INSURANCE

Insurance cost was determined as a percentage of the actual capital cost of the fuel plant and power plant using actual data for fossil-fueled plants from the 18th and 19th Steam Station Cost Surveys (Electrical World; 1973, 1975). The data used was given as a percentage of total capital investment or determined from other data given in the surveys.

The following histograms were obtained from the 18th and 19th surveys, Figures V-5A and V-5B, respectively.

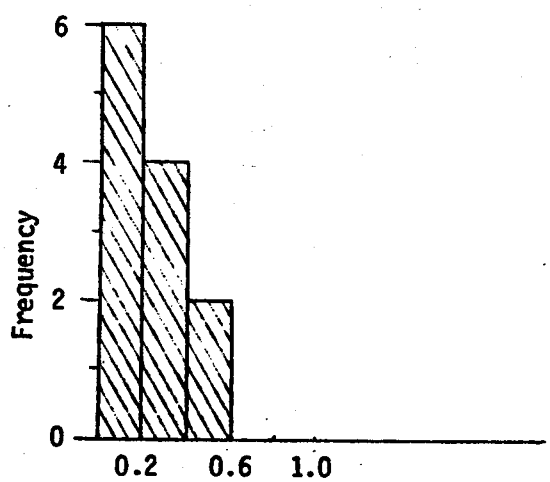


Figure V-5A: Insurance as % of total capital investment.

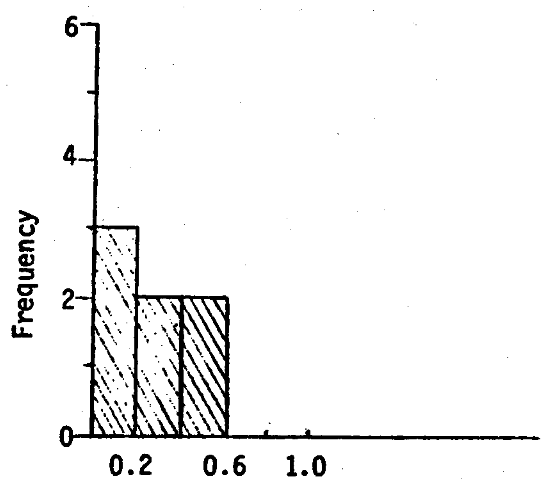


Figure V-5B: Insurance as % of total capital investiment.

From the histograms the insurance cost was estimated to equal 0.35% of the total capital investment in fuel plant and power plant. For 100% tangibles (i.e., intangibles neglected), insurance would be: well field \$145,000, fuel processing plant \$31,000, power plant \$69,000.

TAXES

Property taxes were determined as a percentage of total capital investment, excluding overhead costs. Data for property taxes was also obtained from the 18th and 19th Steam Station Cost Surveys and the following histograms were obtained, Figures V-6A and V-6B, respectively.

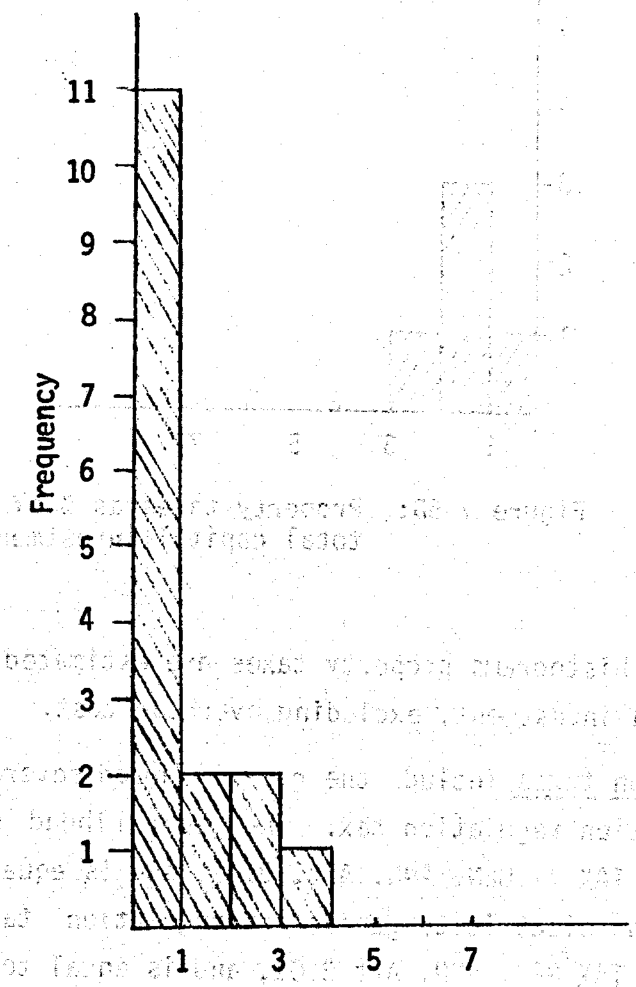


Figure V-6A: Property taxes as % of total capital investment.

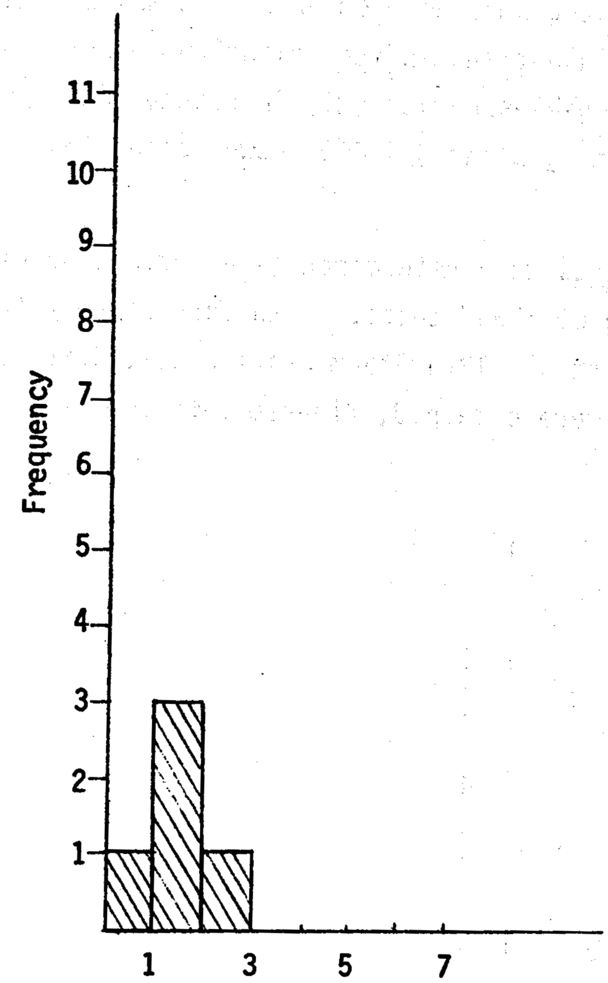


Figure V-6B: Property taxes as % of total capital investment.

From the histograms property taxes are estimated to be equal to 1% of total capital investment, excluding overhead cost.

Production taxes include the gas wellhead severance tax and the electricity generation regulation tax. The gas wellhead severance tax was obtained from TEX. TAX. - GEN. ANN. Art. 3.01, and is equal to 7.5% of the wellhead cost. The electricity generation regulation tax was also obtained from TEX. TAX GEN. ANN. Art 3.01, and is equal to 0.3% of electricity sales. Tables V-12 and V-13 show the estimated values for gas wellhead severance taxes and electricity generation taxes, respectively, for each of the five six-year economic analysis periods.

TABLE V-12

GAS WELL HEAD SEVERANCE TAX

PERIOD	AVERAGE ANNUAL RATE (MILLIONS $)	PRESENT WORTH (MILLIONS $) AT INDICATED DISCOUNT RATE		
		8%	10%	12%
I	0.94	2.59	2.24	1.94
II	1.12	2.06	1.61	1.26
III	1.24	1.55	1.10	0.78
IV	1.41	1.16	0.74	0.47
V	1.58	0.89	0.51	0.30
VI	1.82	0.67	0.35	0.18
TOTAL	1.35*	8.92	6.55	4.93

*Six period average

TABLE V-13

ELECTRICITY GENERATION REGULATION TAX

PERIOD	AVERAGE ANNUAL RATE (MILLIONS $)	PRESENT WORTH (MILLIONS $) AT INDICATED DISCOUNT RATE		
		8%	10%	12%
I	0.028	0.08	0.07	0.06
II	0.031	0.06	0.05	0.04
III	0.036	0.04	0.03	0.02
IV	0.041	0.03	0.02	0.01
V	0.046	0.03	0.01	0.01
VI	0.052	0.02	0.01	0.01
TOTAL	0.039*	0.26	0.19	0.15

*Six period average

Federal Income Tax rate is equal to 48% of gross earnings (total income means total production cost). No specific tax exemptions were included in the project due to lack of information; specific exemptions could change the final financial transaction.

DEPRECIATION

Straight line depreciation is used to devaluate the total investment of the geopressured geothermal power system model considered in this report. It is assumed that this system has an expected economic life of 30 years with no salvage value. Other depreciation methods might well be used, however, none were investigated here.

AMORTIZATION

Amortization annual payments will be equal to the annual depreciation plus 15% of the net income for the year. In each case, this method for amortization results in amortization which is conservative (over predicted).

b. Operations and Maintenance Charges

ROYALTY PAYMENTS

"Royalty payments" include royalty payments on gas production, which are estimated as 12.5% of revenue from gas sales, and royalty payments on the geothermal fluids, which are estimated as 12.5% of the price of the available energy for electric power production. Neither royalty payment includes the actual lease costs and the costs incurred in distributing the royalty payments.

Information for these costs was obtained from general knowledge of oil and gas practice. One might make a case for lower royalty payments; however, it is expected that rates will not go above 12.5%. Thus, the economic analysis is conservative on this point.

Tables V-14 and V-15 present royalty payments for gas production and for geothermal fluids production by economic analysis period.

TABLE V-14

ROYALTY PAYMENTS ON GAS PRODUCTION

PERIOD	AVERAGE ANNUAL RATE (MILLIONS $)	PRESENT WORTH (MILLIONS $) AT INDICATED DISCOUNT RATE		
		8%	10%	12%
I	1.56	6.60	5.70	4.93
II	1.87	3.73	2.92	2.28
III	2.06	2.58	1.82	1.29
IV	2.34	1.95	1.25	0.80
V	2.63	1.48	0.85	0.50
VI	3.02	1.15	0.60	0.32
TOTAL	2.25*	17.49	13.14	10.12

*Six period average.

TABLE V-15

ROYALTY PAYMENTS ON GEOTHERMAL FLUIDS

PERIOD	AVERAGE ANNUAL RATE (MILLIONS $)	PRESENT WORTH (MILLIONS $) AT INDICATED DISCOUNT RATE		
		8%	10%	12%
I	0.34	0.95	0.82	0.71
II	0.39	0.74	0.58	0.45
III	0.45	0.58	0.41	0.29
IV	0.57	0.47	0.30	0.19
V	0.65	0.36	0.21	0.12
VI	0.74	0.28	0.15	0.08
TOTAL	0.52*	3.38	2.47	1.84

*Six period average.

PLANT OPERATIONS AND MAINTENANCE COSTS

Operations and maintenance costs for the geothermal plant were determined as a percentage of total capital investment. The data for fossil-fueled plants was taken from the 18th and 19th Steam Station Cost Surveys. The data used was for plants having a manufacturers rated capacity (size) between 25 MW and 1,000 MW. This data was modified by experience obtained from the Geysers geothermal power plant in California and California's fossil fuel plants.

The data given was the following:

(1) Total net generation of the plant, in 10^6 kW-hr = (X)

(2) Maximum 1 - hr peak in MW, modified since plants do not operate at maximum all the time = (Y)

(3) Operations and maintenance costs, in mills/net kW-hr = (Z)

(4) Investment, in dollars \$/net kW = (I)

From which is obtained:

$$\left\{\begin{array}{l}\text{Operation and Maintenance} \\ \text{as percentage of} \\ \text{Total Capital Investment}\end{array}\right\} = \frac{(X) \times (Y)}{(Z) \times (I)} \times 100 \qquad (6)$$

Results

The results obtained for the different plants is given in Table V-16 and Table V-17 for the 18th and 19th surveys, respectively. Using the data from these tables, the following histograms are obtained: Figure V-7A from the 18th survey and Figure V-7B from the 19th survey.

TABLE V-16

REPORTED PLANT OPERATION AND

MAINTENANCE COSTS - 18TH SURVEY

PLANT	YEAR	LOCATION	MW (Z)	% OPERATION AND MAINTENANCE
Coal	72	ENC	823	1.72
Gas/Oil	71	Pac	803	1.39
Coal	73	MA	708	2.49
Coal	70;71	SA	697	2.11
Coal	63;71	Mtn	650	1.27
Coal	57;71	ESC	676	1.72
Coal	72	SA	565	1.31
Gas	71	WSC	539	2.61
Gas	70;71	WSC	497	1.34
Coal	69;71	ESC	437	1.31
Oil	57;72	MA	443	4.52
Coal/Gas	64;72	WNC	441	2.36
Gas	72	WSC	438	2.75
Coal	64;71	SA	385	3.02
Gas	71	WSC	230	2.93
Gas/Coal	66;71	WNC	219	2.55
Gas	68;71	Mtn	214	2.16
Gas	68;72	WSC	195	1.32
Gas	70;70	ESC	168	2.11
Gas	65;72	WSC	120	4.94
Gas	72	WSC	128	0.72
Gas	72	Mtn	17	4.57

TABLE V-17

REPORTED PLANT OPERATION AND
MAINTENANCE COSTS -19TH SURVEY

PLANT	YEAR	LOCATION	MW (Z)	% OPERATION AND MAINTENANCE
Gas	70;73	WSC	754	2.93
Coal	65;72	ENC	790	5.76
Oil	59;73	SA	816	2.32
Coal	73;73	WNC	642	4.61
Gas	72;74	WSC	644	1.91
Coal	59;72	Mtn	704	5.23
Coal	70;73	SA	700	2.95
Coal	72;74	ESC	591	2.50
Oil	73	SA	-	-
Coal	73	ESC	511	0.88
Coal	73	ESC	505	0.99
Coal	73	Mtn	343	2.31
Coal	-	Mtn	-	-
Oil/Gas	72	SA	83	3.86

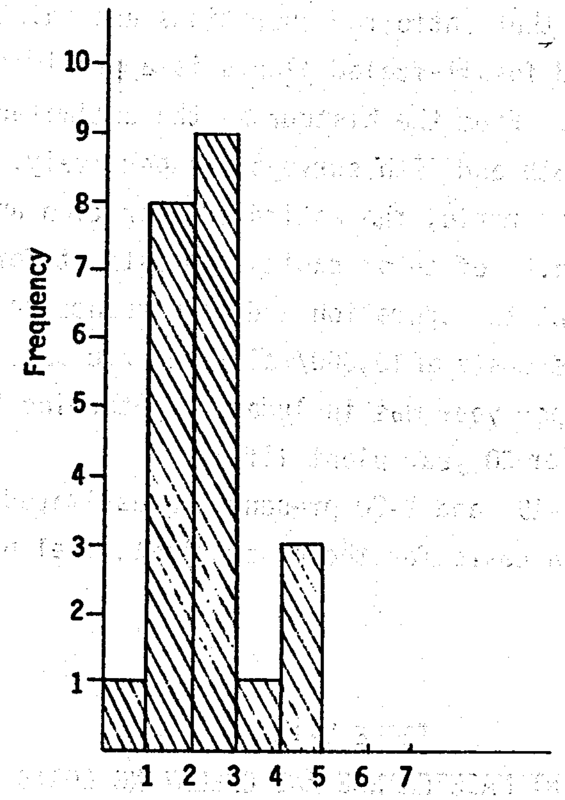


Figure V-7A: Operations and maintenance as % of total capital investment-18th survey.

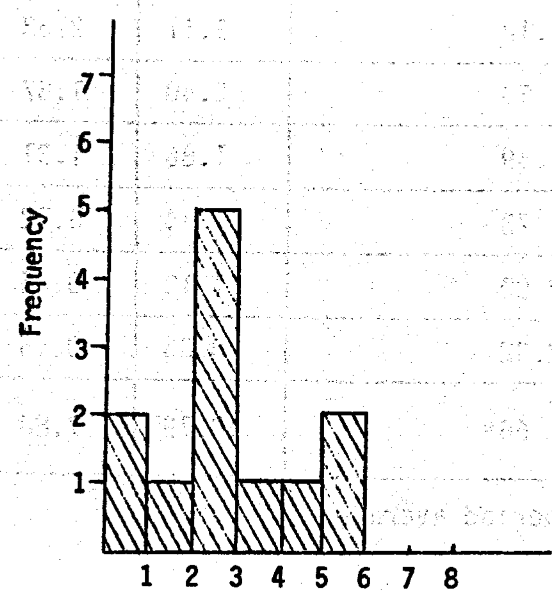


Figure V-7B: Operations and maintenance as % of total capital investment-19th survey.

The Geysers experience, plus experience from California fossil-fueled plants, indicates that ratio for operations and maintenance costs for geothermal plants and fossil-fueled plants is approximately 2.5 (on a dollar investment basis). From the histograms the estimated cost equals 1.95% and 2.5% for the 18th and 19th surveys, respectively. With these observations and the above ratio, the estimated operation and maintenance costs are approximately 6.2% of total capital investment for the geothermal plant. For the fuel plant the operation and maintenance cost is assumed to be 2.5%; well maintenance costs of 10,000/well/year are assumed. An escalation factor of 3% per year was included to determine the cost over the five 6-year periods (or 30 year plant life).

Tables V-18, V-19, and V-20 present the estimated values for maintenance and operation costs for the power plant, fuel plant, and wells, respectively.

TABLE V-18

POWER PLANT MAINTENANCE AND OPERATING COSTS

PERIOD	AVERAGE ANNUAL RATE (MILLION $)	PRESENT WORTH (MILLION $) AT INDICATED DISCOUNT RATE		
		8%	10%	12%
I	1.12	3.11	2.68	2.32
II	1.29	2.40	1.87	1.47
III	1.49	1.86	1.31	0.93
IV	1.73	1.44	0.92	0.59
V	2.00	1.12	0.65	0.38
VI	2.32	0.86	0.45	0.24
TOTAL	1.66*	10.79	7.88	5.93

*Six period average

TABLE V-19

FUEL PLANT MAINENANCE AND OPERATING COSTS

PERIOD	AVERAGE ANNUAL RATE (MILLION $)	PRESENT WORTH (MILLION $) AT INDICATED DISCOUNT RATE		
		8%	10%	12%
I	0.22	0.61	0.53	0.46
II	0.25	0.47	0.37	0.29
III	0.29	0.37	0.26	0.18
IV	0.34	0.29	0.18	0.12
V	0.40	0.22	0.13	0.07
VI	0.46	0.17	0.09	0.05
TOTAL	0.33*	2.13	1.56	1.17

*Six period average

TABLE V-20

WELLS MAINTENANCE AND OPERATING COSTS

PERIOD	AVERAGE ANNUAL RATE (MILLION $)	PRESENT WORTH (MILLION $) AT INDICATED DISCOUNT RATE		
		8%	10%	12%
I	0.10	0.27	0.24	0.20
II	0.12	0.22	0.17	0.13
III	0.13	0.17	0.12	0.08
IV	0.16	0.13	0.08	0.05
V	0.18	0.10	0.06	0.03
VI	0.21	0.08	0.04	0.02
TOTAL	0.15*	0.97	0.71	0.51

*Six period average

E. SUMMARY OF ECONOMIC ANALYSIS

1. CASES STUDIED

Four geothermal system economic analyses cases have been completed:

Case 1: Fuel plant and power plant under single ownership but with appropriate accounting methods applied to each segment; financing is 100% debt with well field development considered 100% tangibles.

Case 2: Fuel plant and power plant under separate ownership with appropriate accounting; financing is 100% debt with well field development considered 100% tangibles; geothermal fuel price varied from $0.05/10^6 Btu to $0.70/10^6 Btu.

Case 3: Fuel plant and power plant under separate ownership with appropriate accounting; financing is 100% debt with well field development considered 45% tangibles and 55% intangibles; geothermal fuel price varied from $0.10/10^6 Btu to $0.50/10^6 Btu.

Case 4: Fuel plant and power plant under separate ownership with appropriate accounting; financing is 100% debt with well field development considered 45% tangibles and 55% intangibles; depletion allowance taken as 15% depletion; geothermal fuel price varied from $0.10/10^6 Btu to $0.50/10^6 Btu.

Factors not considered in performing the economic analysis were:

a. Costs of obtaining geothermal leases (bonuses and legal fees)
b. Costs of accounting and paying royalties to a potentially large number of land owners.

A fifth economic analysis has been performed for the sake of comparison and to provide a benchmark for the geothermal analysis: a 600 MW(e) [net] coal-fired generation plant sited in Central Texas and burning low-sulfur, western coal from the North-Western Great Plains.

2. INTERNAL TRANSFER PAYMENTS FOR HOT BRINE

The price of the hot brine thermal content was varied from $0.05/10⁶ Btu to $0.70/10⁶ Btu. Table V-21 shows the annual hot brine payment from power plant to fuel plant as a function of price of the brine thermal content.

TABLE V-21

PRICES FOR HOT WATER SALES

$ /10^6 Btu	Revenue or Cost * (Million $/yr)	%Fuel Plant Income
0.05	0.3685	2.5
0.10	0.7370	5.0
0.15	1.1055	7.5
0.20	1.4740	10.0
0.30	2.2110	15.0
0.40	2.948	20.0
0.50	3.685	25.0
0.60	4.422	30.0
0.70	5.159	35.0

* Revenue for fuel plant and fuel cost for the power plant

3. RESULTS OF ANALYSES

Case 1: Fuel Plant and Power Plant Single Ownership

The results for Case 1, defined above, are shown in Table V-22 below. The internal rate of return for the single ownership project is slightly greater than 12%. This represents approximately 4% after-tax rate of return on overall investment. Clearly, this is a low rate of return for either oil and gas or utility practice. The effects of the internal payments for hot water thermal content are not included. The distribution of profitability in each segment of the venture is not available. Case 2 was studied to determine these effects.

TABLE V-22

PRESENT WORTH OF PROJECT FACTORS

FACTOR NAME	PRESENT WORTH (MILLION $)			
DISCOUNT RATE	8%	10%	12%	14%
REVENUE	205.20	150.82	113.51	87.23
NET INCOME	154.41	113.27	85.08	65.26
VAR.OF NET INCOME	23.31	17.60	13.64	10.81
DEPRECIATION	-27.04	-21.21	-17.02	-13.93
TAXES	61.14	44.19	32.67	24.63
AFTER TAXES EARNINGS	93.27	69.08	52.41	40.62
INVESTMENT	-60.55	-55.96	-52.08	-48.69
NET PRESENT WORTH	32.72	13.12	0.34	- 8.07

Case 2: Fuel Plant and Power Plant Separate Ownership

In this case, the power plant makes payments for water thermal content to the fuel plant; profitability of each segment of the venture is available. Table V-23 presents the internal rate of return results for fuel plant and power plant as a function of the price, dollars per million Btu's, of the brine thermal content. Notice that the fuel plant is much less sensitive to the price of the brine thermal content. This is because no more than 35% of the fuel plant gross revenue comes from hot brine sales (at $0.70/$10^6$ Btu) while the power plant disburses 24% of its revenue at $0.30/million Btu and 51% of its revenue at $0.70/million Btu to pay for brine thermal content. The power plant after-tax net rate of return decreases from near 10% to zero while the fuel plant after-tax net rate of return increases from about 1½% to about 5% as the brine price increases from $0.00 to $0.70/ million Btu. Table V-24 presents the present worth analysis project factors for the fuel plant and the power plant for a brine thermal content price of $0.30/million Btu. We now ask what effect consideration of drilling intangibles will have on the fuel plant profitability.

TABLE V-23

INTERNAL RATE OF RETURN FACTORS, CASE 2

Fuel Price ($/$10^6$ Btu)	Fuel Plant % I.R.R.	Power Plant % I.R.R.
0.00	10.0	17.5
0.05	10.2	17.0
0.10	10.4	16.5
0.15	10.7	16.0
0.20	11.0	15.5
0.30	11.3	13.6
0.40	11.7	12.4
0.50	12.2	11.1
0.60	12.8	9.8
0.70	13.4	8.5

TABLE V-24

PRESENT WORTH ANALYSIS OF 25 MW(e) FLASH STEAM GENERATION PLANT WITH 30¢/10^6 BTU FLUID PRICE

SUMMARY REPORT PRESENT WORTH OF PROJECT FACTORS

FUEL PLANT FACTOR	DISCOUNT RATE							
	0.06	0.08	0.10	0.12	0.14	0.16	0.18	0.20
Revenue (methane & water)	191.0	137.6	101.7	76.9	59.4	46.8	37.3	30.2
Net Income	143.6	103.3	76.3	57.7	44.5	35.0	27.9	22.6
Depreciation	-27.5	-21.0	-16.6	-13.3	-10.9	-9.2	-7.8	-6.7
Depletion Allowance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Taxes	55.7	39.5	28.7	21.3	16.1	12.4	9.7	7.7
After-Tax Earnings	87.8	63.8	47.6	36.4	28.4	22.6	18.3	14.9
Investment	-48.8	-44.5	-41.2	-38.4	-36.1	-34.1	-32.2	-30.5
Net Present Worth	39.0	19.25	6.4	-2.0	-7.6	-11.4	-13.9	-15.6
POWER PLANT FACTOR								
Revenue (Electricity)	120.2	86.1	63.3	47.7	36.7	28.7	22.8	18.4
Net Income	72.5	51.1	37.0	27.4	20.7	16.0	12.5	9.9
Depreciation	-8.0	-6.0	-4.7	-3.7	-3.0	-2.4	-2.0	-1.7
Taxes	30.9	21.6	15.5	11.4	8.5	6.5	5.0	3.9
After-Tax Earnings	41.5	29.5	21.5	16.0	12.2	9.5	7.5	6.0
Investment	-17.4	-16.0	-14.7	-13.6	-12.6	-11.6	-10.8	-9.9
Net Present Worth	24.2	13.5	6.7	2.4	-0.4	-2.2	-3.3	-4.0

Case 3: Fuel Plant and Power Plant Separate Ownership; Well Drilling Intangibles Allowed

Intangibles have been estimated as 55% of the cost of production and reinjection wells. This amount is costed to time zero while the remaining 45% of drilling costs are treated as investment. Thus, amortization is considerably reduced and local property tax payments on the wells are reduced by 55%. The internal rate of return for the fuel plant will increase, but the power plant internal rate of return is unaffected (assuming fixed fuel price). Table V-25 presents these results, along with the unchanged power plant results from Case 2.

TABLE V-25

INTERNAL RATE OF RETURN FACTORS, CASE 3

Fuel Price ($\$/10^6$ Btu)	Fuel Plant % I.R.R.	Power Plant % I.R.R.
0.10	12.2	16.5
0.15	12.6+	16.0
0.20	12.9	15.5
0.30	13.6	13.6
0.40	14.2	12.4
0.50	14.90	11.1

Note that the fuel plant internal rate of return has increased approximately 1.5 to 2.0%. The approximate after-tax net rate of return approaches 6% for a hot brine price of $0.30/million Btu. This is nearly the rate of return that is produced by the power plant for the same hot brine price. The effect of a depletion allowance will be to further increase fuel plant internal rate of return.

Case 4: Fuel Plant and Power Plant Separate Ownership; Intangibles and 15% Depletion Allowance

A depletion allowance of 15% is applied to the methane content and the thermal content (argued as water percentage depletion allowance with methane and thermal contents properly belonging to the water). Cost depletion is not considered, as lease costs cannot be determined at this time. The results, including intangibles and depletion allowance, are presented in Table V-26 as a function of the price in dollars/million Btu of the brine thermal content. Also shown are the Case 2 results for the power plant so that an easy comparison is possible. Notice that a 6% annual after-tax net return is possible for the power plant with a 7% annual after-tax net return for the fuel plant.

TABLE V-26

INTERNAL RATE OF RETURN FACTORS, CASE 4

Fuel Price ($\$/10^6$ Btu)	Fuel Plant % I.R.R.	Power Plant % I.R.R.
0.10	13.84	16.5
0.15	14.21	16.0
0.20	14.60	15.5
0.30	15.13	13.6
0.40	16.00	12.4
0.50	16.75	11.1

4. SUMMARY OF PRESENT WORTH ANALYSIS FOR GEOPRESSURED GEOTHERMAL PLANT

It is clear from the results of the present worth analysis that, even with the aid of intangibles and a 15% depletion allowance, the after-tax net rate of return for the power plant and fuel plant are best described as marginal. However, as pointed out in Section D, 3, a, the amortization used in the present worth calculations is generally very conservative. The method takes amortization as depreciation plus 15% of net income. Early in plant life (years 1 through 10), depreciation averages about $2.75 x 10^6 per year and net income about $8.25 x 10^6 per year. Amortization thus is about $4.0 x 10^6 annually. This compares with a more conventional consolidated income statement value of about $2.0 x 10^6 annually. Throughout the 30-year project life, the <u>estimated</u> amortization payments exceed the directly calculated amortization payments, except in the nineteenth and twentieth years. For the fuel plant with $0.30/million Btu brine thermal content price, the excess amortization decreases after-tax net rate of return from about 8% to about 5%.

5. CONSOLIDATED INCOME STATEMENT - CASH FLOW ANALYSIS

Table V-27 presents a consolidated income statement summary for the flash-steam fuel plant only. The revenue and expenses are identical to those assumed for the present worth analyses with one exception: the 1976 prices for methane and for hot water thermal content are escalated to 1980 and then held fixed for the period 1980-2020. The expenses and capital costs are escalated to 1980 and held fixed. Well field production is sustained by drilling one production and two reinjection wells every third year for thirty years. This activity results in an increasing total investment. Wells are again depreciated over 20 years while the fuel processing plant and power plant are depreciated over 30 years. The project is run for a period of 40 years, the last 10 years of which are for purposes of depleting the remaining portions of the reservoir (generation ceases after 30 years). Capital costs are taken as 8% per year, a reasonable assumption for a "zero inflation" economy. Amortization is calculated on a declining principal balance.

TABLE V-27

CONSOLIDATED INCOME STATEMENT, DISTRIBUTION OF FUNDS

(FUEL PLANT ONLY) [$$10^6$]

Year	Revenue	Expenses	Depreciation	Net Income	Interest	Taxable Income
1(1980)	14.69	3.54	2.48	8.67	4.16	4.51
10	14.69	3.54	3.17	7.98	4.11	3.87
20	14.69	3.54	3.86	7.29	2.22	5.07
21	14.69	3.54	1.38	9.77	1.79	7.98
30	14.69	3.54	1.61	9.54	1.51	8.03
31	12.46	3.54	1.38	7.54	1.36	6.18
40	8.70	2.55	0.69	5.46	0.49* (-2.74)	2.23
Project	549.48	137.77	89.16	322.55	98.83*	215.50

Year	Tax	Net Profit	Available Distribution	Amortization	After Tax Earnings
1	2.17	2.34	4.82	1.05	3.77
10	1.86	2.01	5.18	2.47	2.71
20	2.43	2.64	6.50	5.74	0.76
21	3.83	4.15	5.53	1.96	3.91
30	3.85	4.18	5.79	2.30	3.49
31	2.97	3.21	4.59	1.40	3.19
40	1.07	1.16	1.85	0.89	0.96
Project	103.41	112.09	201.24	90.33	110.91

*Unamortized investment carried backward for three years as a loss (-2.74) and taxes recomputed.

It is important to note that the well field drilling, to maintain sustained production and reinjection, is assumed to be 50% larger in this calculation than in the present worth calculations. Nevertheless, after-tax rate of return averages approximately 5% over the first 30 years of project life. Again, this is at best a marginal investment proposition which higher energy costs could turn into an attractive investment.

6. CENTRAL TEXAS COAL-FIRED POWER PLANT

A 600 MW(e) coal-fired power plant fueled with low-sulfur western coal was analyzed to provide a benchmark for the geothermal system analysis. Table V-28 outlines the various capital costs while Table V-29 presents the operations, maintenance, and fuel costs. Interest is taken at 8% with 100% debt. Revenues are calculated at 1975 busbar prices of 25, 30, and 35 mills/ kW-hr with fuel price escalation from 1975 to 1980 at the rates of 2½%, 5%, and 7½%.

Tables V-30, V-31, and V-32 present consolidated income statements for 2½%, 5%, and 7½% fuel price escalation rates, respectively, as a function of 1980 busbar price. The following conclusions can be drawn using these tables: the 2½%, 5%, and 7½% annual fuel charge escalation rates yield approximate busbar prices of 26 mills/kW-hr, 27.5 mills/kW-hr, and 30 mills/ kW-hr, respectively.

Certain comments are in order concerning the coal plant analysis. No allowance has been made for the installation of stack-gas scrubbers. Coal plant construction experience from around the midwestern and southern part of the United States indicates that the estimated capital costs are the bare minimum expected for this type of plant. General estimates of investor-owned utilities are that the (1980) busbar price for western coal-fired plant should be approximately 33 mills/kW-hr broken down as follows: Capital - 12 mills, fuel - 18 mills, operations and maintenance - 3 mills. Table V-32 shows that 30 mills/ kW-hr will be subdivided as: capital - 11.7 mills, fuel - 15.6 mills, operations and maintenance - 2.7 mills. Addition of scrubbing equipment to meet air quality standards will result in about a 6 - 10 mill/kW-hr surcharge to all of the above busbar prices.

TABLE V-28

CAPITAL COSTS, 600 MW(e) CENTRAL TEXAS COAL-FIRED POWER PLANT

ITEM	CAPITAL COST($1000)
Site Selection and Acquisition	10,680
Cooling Reservoir, Associated Facilities	11,020
Railroad Spur	690
Coal and Ash Handling Facilities	5,850
Common Plant Equipment	3,330
Railcars for Coal Transport	13,800
Turbine/Generator System; Boiler System (Installed)	148,600
Laboratory, Stores, Fixtures, Lubricants	1,700
Test and Start Up	2,200
Staff Training/Administration	3,550
Professional Services	2,580
Architect/Engineer Fee	9,400
INSTALLED TOTAL CAPITAL COST	213,790
INSTALLED COST, $356/KW	

TABLE V-29

OPERATION, MAINTENANCE, AND FUEL COSTS

ITEM	ANNUAL COST ($1000)	DATE	ESCALATION RATE(%)*
Salaries	3,280	1980	5
Railcar Maintenance	500	1980	2½
Plant Maintenance	6,350	1980	2½
Insurance	780	1980	2½
Property Taxes	410	1980	2½
Generation Regulation Tax	530	1980	2½
General Administration	1,000	1980	2½
Fuel (Coal)	17,000	1975	2½, 5, 7½
Coal Severance Tax (Est.)	5,100	1975	2½, 5, 7½
Coal Transport	22,120	1975	2½, 5, 7½
Levelized Amortization	5,560	1980	None
Levelized Interest	9,256	1980	Interest = 8%

*Escalation considered 1975 – 1980 or 1976 – 1980.

TABLE V-30

600 MW(e) COAL PLANT-CONSOLIDATED INCOME STATEMENT

(2½% FUEL PRICE ESCALATION RATE)

1980 Busbar Price (Mills/kW-hr)→	25	30	35
↓ Factor ($$10^6$)→			
Revenue	105.2	126.2	147.2
Operations	-62.8	-62.8	-62.8
Net Revenues	42.4	63.4	84.4
Depreciation	-5.6	-5.6	-5.6
Net Income	36.8	57.8	78.8
Interest	-9.3	-9.3	-9.3
Taxable Income	27.5	48.5	69.5
Federal Income Tax	-13.2	-23.3	-33.4
After-Tax Earnings	14.3	25.3	36.1
Available for Distribution	19.9	30.9	41.7
Amortization	-5.6	-5.6	-5.6
Net Profit	14.3	25.3	36.1
After-Tax Return(%)	8.5	15.2	21.6
Busbar Distribution (Mills/kW-hr)			
Operations, Maintenance	2.7	2.7	2.7
Fuel	12.2	12.2	12.2
Capital	3.6	3.6	3.6
Profit	3.4	6.0	8.6
Tax	3.1	5.5	7.9

TABLE V-31

600 MW(e) COAL PLANT-CONSOLIDATED INCOME STATEMENT

(5% FUEL PRICE-ESCALATION RATE)

1980 Busbar Price (Mills/kW/hr)→	25	30	35
↓ Factor ($$10^6$)→			
Revenue	105.2	126.2	147.2
Operations	-69.9	-69.9	-69.9
Net Revenues	35.3	56.3	77.3
Depreciation	-5.6	-5.6	-5.6
Net Income	29.7	50.7	71.7
Interest	-9.3	-9.3	-9.3
Taxable Income	20.4	41.4	62.4
Federal Income Tax	-9.8	-19.9	-30.0
After-Tax Earnings	10.6	21.5	32.4
Available for Distribution	16.2	27.1	38.0
Amortization	-5.6	-5.6	-5.6
Net Profit	10.6	21.5	32.4
After-Tax Return(%)	6.4	12.9	19.4
Busbar Distribution(Mills/kW-hr)			
Operations, Maintenance	2.7	2.7	2.7
Fuel	13.9	13.9	13.9
Capital	3.6	3.6	3.6
Profit	2.5	5.1	7.7
Tax	2.3	4.7	7.1

TABLE V-32

600 MW(e) COAL PLANT-CONSOLIDATED INCOME STATEMENT

(7½% FUEL PRICE ESCALATION RATE)

1980 Busbar Price (Mills/kW-hr)→	25	30	35
↓ Factor ($$10^6$)→			
Revenue	105.2	126.2	147.2
Operations	-77.1	-77.1	-77.1
Net Revenue	28.1	49.1	70.1
Depreciation	-5.6	-5.6	-5.6
Net Income	22.5	43.5	64.5
Interest	-9.3	-9.3	-9.3
Taxable Income	13.2	34.2	55.2
Federal Income Tax	-6.3	-16.4	-26.5
After-Tax Earnings	6.9	17.8	28.7
Available for Distribution	12.5	23.4	34.3
Amortization	-5.6	-5.6	-5.6
Net Profit	6.9	17.8	28.7
After-Tax Return (%)	4.1	10.7	17.2
Busbar Distribution (Mills/kW-hr)			
Operations, Maintenance	2.7	2.7	2.7
Fuel	15.6	15.6	15.6
Capital	3.6	3.6	3.6
Profit	1.6	4.2	6.8
Tax	1.5	3.9	6.3

F. SUMMARY AND CONCLUSIONS

The economics of the production of electricity from geopressured geothermal generation plants are not now as attractive as generation in western coal-fired plants. The coal-fired plant, without stack-gas scrubbers, will produce electricity at approximately 70% of the busbar price of the geopressure geothermal plant. A coal-fired plant with stack-gas scrubbers will produce electricity at about 85 - 90% of the geopressure geothermal busbar price. However, increasing fossil-fuel prices will tend to improve the geothermal plant's economics while tending to worsen those of the coal plant.

REFERENCES

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